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EXCEPTION

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BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
COMMISSIONER-CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
CARL J. KUNASEK
COMMISSIONER

DOCKET NO. U-00000C-94-165

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	**NOTICE OF FILING OF EXCEPTIONS ON BEHALF OF ELECTRIC COALITION, ENRON CORPORATION AND ENRON ENERGY SERVICES, INC.**

NOTICE is given that the Electric Competition Coalition (ECC), Enron Corporation and Enron Energy Services, Inc. filed their Exceptions.

RESPECTFULLY submitted this 29th day of May, 1998.

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Douglas C. Nelson

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Arizona Corporation Commission
DOCKETED
MAY 29 1998
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ORIGINAL and ten copies of the Notice and Exceptions were filed this 29th day of May, 1998 with:

Docket Control Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

TWO COPIES of the Notice and Exceptions were *hand-delivered* this 29th day of May, 1998 to:

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BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
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IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. U-00000C-94-165

EXCEPTIONS TO THE RECOMMENDATION OF THE HEARING OFFICER FILED BY ELECTRIC COMPETITION COALITION, ENRON CORPORATION AND ENRON ENERGY SERVICES, INC.

MAY 29, 1998

EXCEPTIONS TO STRANDED COST PROPOSED ORDER

The Electric Competition Coalition, Enron Corporation, and Enron Energy Services, Inc. (collectively "ECC/Enron") file these Exceptions to the recommendation of the Hearing Officer, dated May 6, 1998. The recommendation was filed in the form of an Opinion and Order in *Competition of Electric Services Throughout the State of Arizona* in this docket ("the Proposed Order").

Exception No. 1. Encouraging the Competitive Sale of Generation and the Use of Market-Derived Values Are Also "Primary Objectives"

The Proposed Order, on page 8, properly identifies six objectives: the reasonable opportunity to collect 100 percent of unmitigated stranded costs, incentives to maximize mitigation efforts, accelerate the stranded cost recovery into as short of a transition period as possible consistent with other objectives, minimize their impact on standard offer customers, don't confuse customers as to the bottom line, and pursue full generation competition as soon as possible.

Stranded costs arise when two conditions occur: a meaningful number of customers are buying competitive generation and the Affected Utility has unmarketable generation that costs more than market-priced generation. Stranded costs occur only <u>after</u> a robust competitive generation market has developed. Stranded costs may only be measured by comparing generation costs to <u>market prices</u>. Recognizing these cornerstones of stranded cost recovery, we urge the Commission to add these "primary objectives" to the analysis, on page 8, line 17½:

G. Minimize the impact of stranded cost recovery on the effectiveness of competition and on consumers who participate in the competitive market.

H. Provide sound and meaningful opportunities for the competitive sale of generation.

These objectives are consistent with the existing Electric Competition Rules. Two of the factors for consideration by the Commission are the impacts of stranded cost recovery on the effectiveness of competition and the impact of stranded cost recovery on prices paid by consumers who participate in the competitive market. A.A.C. R14-2-1607.I. 1 & 4.

Exception No. 2. The Net Revenues Lost Methodology Overstates Stranded Costs and Will Discourage and May Preclude Competitors from Entering the Market

Option No. 1 suggests a Net Revenues Lost Methodology similar to that proposed by Arizona Public Service Company, on pages 11 and 12 of the Proposed Order. We oppose the use of any net revenues lost approach. We urge that Option No. 1 be deleted from the Proposed Order starting on page 11, line 11 through page 12, line 15, with "Option No. 2" on page 12, line 16 changed to "Option No. 1," "second" changed to "first" option on page 12, line 17, "Option No. 3" on page 12, line 23½ changed to "Option No. 2," and "third" option changed to "second" option on page 12, line 24½.

The net revenues lost approach falsely assumes all differences in revenue, before and after January 1, 1999, are due entirely to the adoption of these Rules. It encourages inefficiencies because all future costs are either recovered from standard offer rates or the competitive transition charge ("CTC").

The net revenues lost approach discourages the marketing of generation because the CTC floats depending upon management decisions of the Affected Utility. Neither the customer nor new entrant will know if the standard offer or the market generation price -- with the CTC -- is the least-cost alternative. Customers will be disinclined to pursue competitive generation and they will likely stay on the standard offer.

The net revenues lost approach sends all the wrong signals. An Affected Utility would be encouraged to raise the CTC because all of its <u>future</u> generation and other costs would be compared to market prices in figuring the CTC. Inefficient plants would still be run. The Affected Utility is guaranteed the same revenue stream without any consideration of future inefficiencies in its operations. All ongoing costs, including operation, administrative and general costs, would be recoverable under the net revenues lost approach, either through the standard offer or the CTC. The Affected Utility would have the incentive to run up costs so as to keep the CTC high, squeeze out competitors, and deny consumers choice by keeping them on the standard offer.

The net revenues lost approach overemphasizes the near-term when market prices are thought to be low and ignores the long-term when these generation assets might provide considerable value and revenues to the Affected Utility. Customers pay a higher than reasonable CTC, the Affected Utility retains the revenue-producing generators, and competitors are discouraged from entering or staying in the market.

The Proposed Order says the Net Revenues Lost Methodology creates "little incentive for customers to utilize another competitive service as they would have to purchase generation at below market price in order to reap any savings." Proposed Order at 11 and Findings of Fact No. 26 at 22. A new entrant cannot afford to sell generation below its market price if it wishes to remain in business. The Net Revenues Lost Methodology creates no incentive for a competitor to enter the market.

The Proposed Order recommends an incentive for customers to purchase competitive power. It suggests an 80-60-40-20 percent decline in the CTC portion paid by purchasers of competitive generation over a five-year period. Although some anticompetitive effects of the net revenues lost approach may be ameliorated to some degree by using this declining percentage program, it still gives the Affected Utility control over the market and the ability to keep out competitors.

Exception No. 3. Divestiture/Auction Methodology for All Generation Assets Provides a Fair and Equitable Basis for Determining Stranded Costs

ECC/Enron strongly supports the divestiture/auction approach for determining stranded costs. This method is referenced as Option No. 2 on page 12. We urge that the reference to "all non-essential" generation assets be deleted on page 12, line 17½. Instead, we recommend that the Affected Utility petition the Commission for a limited divestiture waiver of a particular generation plant, following a reasonable attempt to sell the plant and after showing cause why that plant is not marketable. We suggest the following paragraphs be added on page 12, line 23:

> Each Affected Utility shall file a divestiture plan or a Financial Integrity plan, referenced as Option No. 2 below, no later than August 1, 1998. If an Affected Utility chooses to divest of all of its generation assets, the divestiture must be completed no later than January 1, 2000.
>
> If an Affected Utility has made all reasonable efforts to divest of it generation assets and if there is no market for such asset or assets, the Commission may, upon the petition by the Affected Utility or interested party, examine the circumstance for such nondivestiture, and upon the showing of good cause, in the public interest, grant a limited waiver for such asset or assets and require that such asset or assets be appraised by a third-party independent appraiser selected by the Commission and that appraised value will be used in determining any stranded costs.
>
> An Affected Utility shall be provided a reasonable opportunity to collect the Commission-approved verifiable and unmitigated stranded costs over a reasonable period of time which fosters the sale of competitive generation and such that stranded costs imputed presently within the rates of all of its customers shall not be increased above the proportionate share of stranded costs paid by those customers under present rates. Reasonable and prudent costs associated with the completion of divestiture may be recoverable as stranded costs, subject to review and approval by the Commission. All customers of the Affected Utility shall pay their appropriate share of stranded costs through a CTC or as a line-item of the imputed amount within the standard offer rate or special contracts.

Exception No. 4. The Stranded Cost Amount and Recovery Methodology Should Not Increase the Relative Proportionate Share that All Customers Are Paying Today.

The Proposed Order addresses whether or not there should be a price cap or rate freeze on page 18. ECC/Enron strongly supports a "rate" cap and opposes a rate freeze. The following example explains the importance of a rate cap, its significance on the ability of new entrants to compete, and why the net revenues lost approach creates pressure for rate increases.

Today an Affected Utility's cost of service may be $0.09 per kilowatt hour, of which $0.03 is for generation, $0.01 is an imputed stranded cost charge on that generation to the extent generation costs are higher than market rates, and $0.05 is for distribution and other costs. In the future, the standard offer customer would still pay the imputed $0.01 stranded cost within that rate. Today a special contract customer may be paying $0.085 per kwh which would also include those components of generation costs, imputed stranded cost charge, and distribution and other costs. In the future, the special contract customer will still be paying the imputed stranded cost within its rate. <u>We urge that the stranded cost component for all customers shall not exceed what is being paid in rates today</u>.

No customer should be required to pay more for stranded cost in the future than is imputed in rates or special contracts today. If the stranded cost component may be increased for any customer after competition begins, then the stranded cost recovery method is not neutral and both the standard offer customer and special contract customer are given disincentives to seek competitive generation. In order for new entrants to compete, the amount of stranded cost cannot be increased above present levels for any customer.

The net revenues lost approach and a short period of recovery will cause rates to be higher than those experienced by customers today. The Affected Utility would be guaranteed a revenue stream in the future which equals that which might have been received before competition occurs and any differential would be recovered as stranded costs. This approach would require that stranded costs be increased in the future for all customers. This is another reason why we urge the Commission not to adopt the net revenues lost approach.

We support a cap on the standard offer and special contracts so that new entrants will have an incentive to provide competitive generation, for the reasons discussed above. The Commission should require the Affected Utility to take all reasonable mitigation measures and adjust the stranded cost recovery period so as to assure all customers that no rate will be increased during the transition period. This assurance protects all consumers and gives new entrants the incentive to market generation.

We recommend that the text on page 18, lines 15 to 22, be deleted and that the following be inserted:

We share the concerns expressed by all groups that stranded costs should not be used to raise rates or discourage the marketing of competitive generation. We have placed a limitation that all customers will not receive a rate increase as a result of stranded costs. Affected Utilities must adopt all reasonable mitigation efforts and the recovery period must be adjusted so that there shall not be any rate increase during the transition period.

CONCLUSION

ECC/Enron incorporates by reference the arguments presented in its Initial Brief dated March 16, 1998, and its Reply Brief dated March 23, 1998, in these Exceptions. ECC/Enron further incorporates within these Exceptions and attaches hereto the Comments prepared by Mr. James K. Tarpey, Director of Government Affairs, Enron Corp., and Mr. Tom Delaney, Director of Federal Regulatory Affairs, Enron Corp., dated May 22, 1998. These Comments address stranded costs and the critical conditions for creating a competitive generation market, such as affiliate rules and functional separation of regulatory and merchant activities, metering and billing programs, and independent and nondiscriminatory transmission access for direct retail wheeling of competitive generation.

RESPECTFULLY submitted this 29th day of May, 1998

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May 22, 1998

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Dear Mr. Williamson:

In response to Staff's Statement of Position dated May 19, 1998, the following comments track the headings in your letter. In addition, Tom Delaney has forwarded comments to you regarding areas within his expertise and they will not be repeated here. Enron appreciates the efforts being made by Staff. However, it needs to be realized that we are responding to general concepts. The viability of the approach is very dependent upon the details. Enron is very concerned about the approach the utilities will take with respect to any issue left to their discretion.

A. Stranded Cost

Stranded costs are, by definition, costs that are caused by competition. To the extent the Rules, or the procedures implementing the Rules, do not provide for fully effective competition because barriers to entry for new entrants are not minimized or the monopoly advantages of the incumbent utility are not corrected for, then a reasonable opportunity for 100% recovery of stranded costs is not appropriate. The link between these two concepts needs to be made clear in the Rule.

Enron agrees that it is important to have a deadline for the completion of the sale process; the Staff is recommending a date of January 1, 2000. To achieve that goal, a deadline for the filing which starts the approval process needs to be included. The sale process itself (from sending the bid package to prospective purchasers through the bidding process and final selection of the purchaser) can easily take 6 months. Therefore, ACC approval of the bid process must be completed by June 1999. The ACC approval needs to be done in the context of resolving such issues as the unbundling of rates, the parameters of standard offer and whether the transfer of any assets must be restricted. As a result, utilities should be directed to make the appropriate filings in the near future and, in any event, no later than August 1 or so.

Staff proposes that open access for certain customers commence on January 1, 1999. However, we do not know how many customers will be able to take advantage of that opportunity. For example, the utilities may argue that customers with special contracts are precluded from making any choices until the contract expires. As a result, it would not be appropriate for recovery of stranded costs to begin on that date.

As for the option to transfer generating assets to an affiliate, the ACC must first address the issue of market power. It very well could be that such a transfer raises impermissible market power concerns. Further, it will be imperative that effective standards of conduct be implemented; it is obvious that one of the prime reasons for a utility to choose this option is the ability to unfairly leverage its monopoly advantage.This is discussed in more detail later. Finally, it is imperative that any calculation of stranded cost must be a market test for all the reasons Enron stated in the stranded cost proceeding

The option regarding financial integrity needs further explanation regarding its limited availability. While the goal may be laudable, it should be clear that its availability is very limited.

One of the goals not mentioned by Staff is that the recovery of stranded costs will be competitively neutral. In addition, the Rule should explicitly state that the calculation of, and recovery method for, stranded cost shall not impede effective competition. For example, the recovery mechanism should not operate in such a way that effective competition will not occur until after the recovery of stranded costs.

B. Affiliate Rules

As the Staff indicates, full divestiture is preferable to transferring assets to an affiliate. The latter is not being considered as an option because it has inherent value as we move toward competition and should be recognized as such. Therefore, it is imperative that the ACC require complete separation of functions into separate affiliates and also adopt a strict code of conduct. The list of goals in this section should be expanded to include: to require functional separation and to adopt strict standards of conduct in order to foster competition.

The complete separation should require that regulated functions be separated from functions that are competitive now or in the near future. This would include energy as well as metering, billing, collection and any related services.

Any interaction between affiliates must be governed by the Golden Rule and the standards of conduct need to be prescriptive. Their purpose is to make clear what is and is not permissible in advance to a wide variety of persons: utility employees, customers, competitors and Commission Staff.

Enron believes it is imperative for the Commission to adopt standards very similar to what has been adopted in California. Along those lines, it is not appropriate to consider any exceptions regarding cost sharing or joint marketing. In addition, the Rule should prohibit the affiliate from using the name, logo, service mark, trademark or trade name of the utility.

Enron assumes various parties will argue that savings will be lost if the utility is not able to share costs with its affiliates. This argument is akin to the argument that a rate decrease under regulation is better than the benefits to be realized under competition. These arguments, at best, are very short-term in outlook. In the long run, customers are the losers.

It also is imperative that the Rule specifically address enforcement provisions and be clear with respect to the penalties. The goal should be to discourage penalties in the first place and provide a disincentive against "pushing the envelope".

C. Implementation of Competition

1. Timing and Customer Selection

The purpose of the threshold is to make competition available to a significant group of customers. However, we do not know if the 1 MW threshold is appropriate because we do not know how many customers will have the opportunity to take advantage. If a significant number of these customers are precluded at present time, then the threshold needs to be lowered.

The concept of aggregation should be broadly construed. The aggregation of loads should not be limited in any way to restrictions such as common entity or ownership requirements. Also, the ACC should define threshold level loads as the individual customer's peak hourly energy usage in the most recent 12 month period. For those customers at 20 kw and higher that do not have metering equipment capable of capturing peak load, a peak monthly kwh equivalent (e.g.,6,000 kwh) should be allowed in determining eligibility.

2. Targeted Rate Decreases

The ACC should make it clear that utilities are expected to address any rate decreases through cost cutting measures or similar steps. The amount associated with the revenue decrease should not become a component of stranded cost calculations. Otherwise, customers will not receive the benefit of a rate decrease; all they will receive is a rate deferral.

Assuming the rate decrease is to become effective on January 1, 1999, the ACC should specify when the utilities will make their filing and provide enough time for input from interested persons.

3. Residential Phase-In Program

Whatever percent is enunciated, the ACC needs to make it clear that this is the target number of customers to be signed into the program. It should not be the % that receives a mailing indicating they can pursue this option if interested. The utility should not have a role in deciding who these customers are.

As for the percent, it is far too low. The initial target should at least be in the neighborhood of 5% and the goal should be to reach 10% or higher within 12 months. The program needs to be of sufficient scale to accomplish two goals: to attract enough suppliers so that the phase-in is meaningful; to sufficiently test the system and be comfortable that the move to 100% on January 1, 2001 can be done. In this regard, any suggestion by the utilities that 1/2 of 1% means an offer only ought to be indicative of how little movement one can expect from the utilities when matters are left to their discretion.

D. Metering and Billing

1. Metering

The metering and billing credit needs to be resolved soon. Unless competitors know the amount of the credit, it will not be possible to make appropriate decisions.

In the situation where a customer has chosen an ESP, whether metering is provided by the utility or the ESP is to be decided by the ESP and not by the utility.

The format of the Universal Node Identifier should be developed for statewide usage through ACC proceedings. Also, a date for compliance with this provision needs to be established. Finally, a significant amount of clarification is needed regarding the EDI format.

2. Billing

With respect to connects and disconnects, it needs to be clarified that the provision of physical connection and disconnection, when accomplished through the legitimate installation or removal of an electric meter, is defined as a competitive function and is subject to the ACC's rules and regulations regarding that type of transaction.

With respect to delinquent bills, it is only the utility portion that is subject to the affected utility's termination policies. If the ESP is no longer going to serve a customer, the customer will get service from another ESP or get standard offer service; the action taken by the first ESP (no longer providing energy service) should not be subject to the utility's procedures.

E. Local Distribution Company Services

1. Standard Offer

Customers should be allowed to change suppliers at any time. If done other than at the end of a cycle, there may be an appropriate charge but there should be no other constraints.

Leaving aside who provides standard offer, it should not be priced in a way that is anticompetitive. If the price is kept too low, then the ACC will be assuring that competition does not occur. An example of how it can be done effectively is the Pennsylvania situation where the standard offer allows for meaningful competition.

If the question is who provides the supply for the standard offer customers,this should be the subject of competitive bid. There is no reason to delay that approach until after the transition period.

As for standard offer itself, the ACC should not restrict its options to the one just mentioned. The ACC should evaluate different appraches to standard offer and allow competitive bidding for the package; a time limit of one or two years could be put on the package so the ACC is not isolating itself from changes in the marketplace. For example, the ACC may set forth the parameters for standard offer and leave flexibility regarding the pricing of various components. Then, entities could bid on that package and the most competitive bid would be chosen. Another approach would be to divide up the service territory and have a standard offer for each of the areas. This would allow the ingenuity of the marketplace into the process and result in a better deal for customers. Again, we should not assume that the standard offer is today's bundled service.

2. System Benefits

Enron supports the concept of a system benefits charge. The Rule needs to clarify that this will be a distribution charge.

F. Transmission and Dispatch

As previously indicated, Tom Delaney has already submitted comments regarding this section.

Again, we appreciate the work you are doing and hope the above comments are helpful. If you have any questions or need further clarification, do not hesitate to call me.

Very truly yours,

James K. Tarpey

James K. Tarpey, Director

Hi there Ray, long time huh. Anyway I read the ACC staff position statement. I thought it rather good. In fact in my area of wholesale regulatory affairs, I was pleased to see that the commission staff took some of the watered down ISA language that the utilities got into the matrix I've attached.

Let me make the following comments from my end knowing that Jim Tarpey might from his state ends as well.

1. Under the heading of "affiliate rules"

The statement of

"The Affected Utility must offer the same terms and conditions of service to all competitors and their customers as it offers to any of its affiliates and their customers. An Affected Utility shall neither provide, nor represent that it will provide, preferential treatment to its affiliates or its customers as compared to nonaffiliated companies or their customers."

Is a very important issue and this statement is greatly appreciated. Still, there has been a lot of discussion on who has what rights to the system. The utilities have been trying to argue that the transfer capability rights of the transmission and distribution (T&D) system goes with the existing generators and not the loads. Furthermore, they believe that in determining the committed use of the system that "native load" gets first cut. In their minds"native load" is the utility merchant function. Native load must be considered a wires, not merchant, function. By 1/1/99 all ESP's including Enron, affected utilities, and other aggregators will be serving native load. If native load is considered a "merchant" definition, then in determining committed usage of the system all those individuals leaving affected utilities to go to new ESP's will be on the margins and at risk.

In truth, the embedded cost of T&D is being paid for by load. The utilities own the facilities, but load in paying for the embedded cost of the system gets the "rights" to the transfer capability of the system. Right now the"steward" of these rights for loads is the affected utilities. But when loads leave the effective utilities, they go and take their rights to the transfer capability of the system with them. The new steward of these rights are whom every they choose as a new ESP. Furthermore, the committed use determination of the system still follows such right-holders. Therefore, when 20 percent of the load is open for retail access in 1/1/99, at minimum a pro-rata share the T&D systems transfer capability of the system. It's very important to make it very clear that

- the load has the "right" to the transfer capability of T&D and not generators,
- native load is wires,
- committed use of the system is done independently and honestly,
- Not let the utility merchant function have the first cut leaving loads not served by utility merchant functions on the margins.

1. Under the heading of "transmission and dispatch."

   The goal statement of

> *"To ensure fair and non-discriminatory retail access to the transmission* ***and*** *distribution system "*

Is a very important and good statement. But if the distribution wires business is not separated from remaining utility business lines (and especially the business of serving bundled customers), the role of administering access to distribution systems cannot be left to the distribution wires' owners. This too must be administered under a strong and independent ISA. Transmission and distribution wires operation, and control area operation, must be performed by entities that are independent of generation and independent of responsibility for energy services provision (i.e., do not act as Load Serving Entities). A truly independent ISA can accomplish this until a regional ISO develops. When an ISO emerges the ISA must still administer

- the scheduling of and distribution wires
- Schedule (receive and coordinate) nominations for use of Distribution wires (day-ahead and hour-ahead)
- Develop and convey secure operating plan to CAOs (validate sufficiency of ancillary services, schedule "reliability must-run" resources, eliminate intra-zonal congestion, ensure coordinated maintenance plan for transmission)
- Make longer-term rights available to the marketplace (FTR auction)

The utilities in the ISA workshops have continually said that various items that the ISA will do will need to be "staged-in", and that full ISA independence can't be accomplished by 1/1/99. In my view this has been nothing but utility foot dragging as a means to scuttle the Independence of a good ISA and further put into the utilities hands an ability to discriminate. So, as an interim measure, the requisite staging can be done, provided that certain standards of independence are met, including separate staffing, a strong Code of Conduct, strong affiliate competition rules (which must also apply to and residual load-serving activities conducted by the utility), and an effective, independent dispute resolution process.

In the attached matrix you'll see that the language and function found in this matrix does not make the ISA truly independent. The ISA will require greater strength in the areas of oversight necessary to remove, (from wires businesses that are affiliated with generation, merchant or energy services businesses) decision-making regarding (i) transmission rights allocation and distribution rights allocation, (ii) curtailment, and (iii) dispatch of reliability must-run resources.

This language need to change for there to be an "I" in the word "independence" in all areas of access including committed usage of T&D, curtailment priorities through voluntary redispatch, curtailments in general, dispatch of must-run units, and ADR processes.

1. As a last item under the heading of "transmission and dispatch"

   The statement of;

   Affected Utilities must join an independent system operator whose activities include, but are not limited to, the following:

   3. *Managing congestion and establishing congestion pricing;*

Is a function of any regional ISO or ISA such as Desert Star. Desert Star (DS) is leaning toward allocating Firm Tradable Right (FTR's) up to the Total Transfer Capability (TTC) of commercially significant interfaces. DS is leaning toward a decentralized approach to congestion management, which means it will only accept schedule nominations up to the TTC level and no more. There will be no counter-scheduling through DS. If you need generation on the other side of the constraint then you'll have to go get it in the market place on your own, DS will not play this role. This is in fact a form of congestion management and its pricing on a day-a-head and an hour-a-head basis. DS still will perform congestion management in real time by utilization of voluntary redispatch before it resorts to involuntary remedies for emergency redispatch purposes.

Last, as a point, uniform statewide tariffs, applicable to all wires owners, should cover:

- Transmission access
- Distribution access
- Ancillary Services
- Imbalance Energy
- Load Profiling
- Appeal of all grievances to an independent body
- Other terms and conditions of retail access

Transmission services: if provided under a state-wide modified FERC 888 tariff: some of the modifications include:

1. No "native load" preference in scheduling or other areas (all parties take services on an equal basis), the right of the system goes with load, not generators.
2. Change scheduling deadlines, ancillary services and losses obligations to meet new requirements
3. Eliminate ability to withhold capacity (transmission rights become "use-or-lose")
4. Commitment to make rights available for FTR creation and auction (if necessary on interim basis)
5. Possible changes to address efficient allocation of transmission uses and/or to address Pancaking (Note: there is probably no need to convert from RSP rights to zonal model, at this stage.)

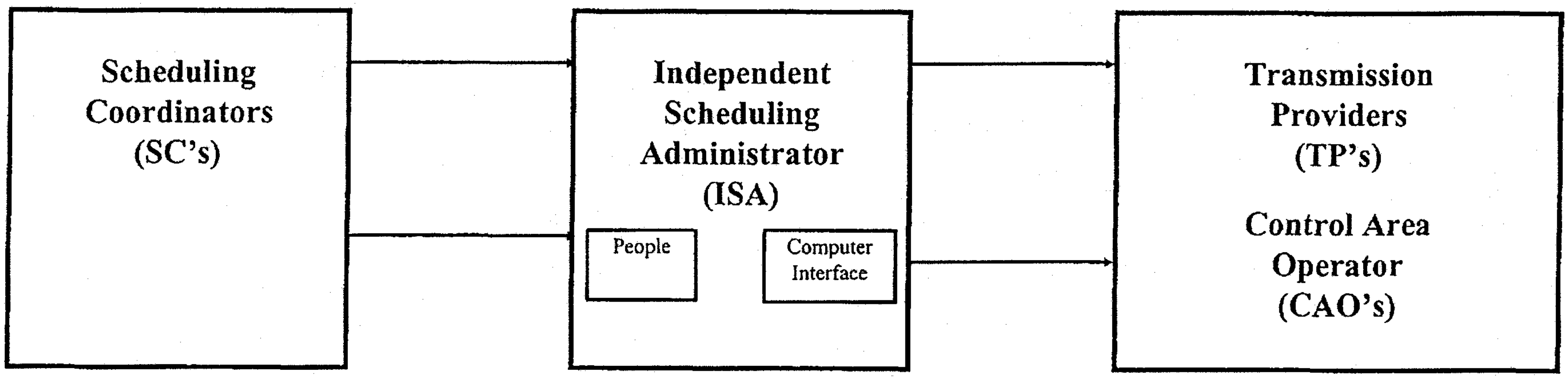
Distribution services: if provided under state-wide distribution tariff: must include functional unbundling/strict separation of wires from all other activities, retail access rules, settlements, independent administration of access and dispute, code of conduct, affiliate standards...

Ancillary services under state-wide tariff: must include obligation to make them available, modified imbalance energy provisions to accommodate direct access…

Ray, thank you for letting me comment on this very good piece of work done.' I'm hoping my point with strengthen the process. Please feel free to contact me at any time.

Tom Delaney – Enron Corp.
Director, Federal Regulatory Affairs

SC/ISA/TP/CAO FUNCTIONS
For 1/1/99 Implementation



	SC's	ISA	TP's & CAO's
Future		1. Participate in the processes of: ▪ Operating Studies used to determine TTC from 1/1/99 until such time as expertise/funding allows for independent calculation of TTC ▪ Maintenance schedules of Transmission ▪ Control Area Operator TTC determination	1. Production of: ▪ Operating studies for TTC determined ▪ Determine TTC and allocate to path owners ▪ Publish Transmission maintenance schedules
Day Ahead	1. Forecast load requirements for day-ahead 2. Acquires necessary transmission and distribution 3. Arranges for appropriate ancillary services 4. Submits balanced schedules (load + loss = gen) to ISA & CAO simultaneously and provides necessary NERC/WSCC tags	1. Responsible for calculation of ATC 2. Operate over arching state-wide OASIS ▪ All ATC posted here ▪ All loads scheduled here ▪ All Xmiss reservations requests made here ▪ Ancillary Services posted here ▪ Secondary transmission posted here 3. Receives copy of transmission schedule and update ATC after receipt of confirmed schedule 4. Receives additional requests for transmission and update ATC	1. Process, review SC's schedules, submit existing contract schedules to ISA, submit generation participants schedules to ISA 2. Posts ancillary services to ISA's OASIS 3. Processes additional schedules from transmission reservation updates 4. Participates in activities for checkout/settlement process for previous day 5. Publish next day operating plan to ISA
Current Day	1. Additional schedules submitted to ISA & CAO with tags 2. Responds to contingencies and curtailments as directed by control areas (7 X 24 ops)	1. Receives and posts curtailment information 2. Provides appeals process for transmission use denials on day ahead process	1. Manage Real-time operations and specify curtailment and contingency actions 2. Processes additional schedules from transmission reservation updates
After the Fact	1. Participates in checkout/settlement process and provide metering information	1. Facilitate ADR process	1. Participates in the checkout/settlement process